September 10, 2007

Mary L. Cottrell, Secretary
Department of Public Utilities
One South Station - 2nd Floor
Boston, Massachusetts 02110

Re: D.P.U. 07-50 Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources

Dear Ms. Cottrell:

Concentric Energy Advisors, Inc. ("CEA") is pleased to submit the enclosed Comments on issues relating to the Department's Investigation in the above-referenced proceeding. These comments have been prepared on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company ("The Companies") by John J. Reed, Chairman and Chief Executive Officer and by James D. Simpson, Vice President.

On behalf of The Companies, I welcome the opportunity to participate in the Department's Investigation.

Very truly yours,

CONCENTRIC ENERGY ADVISORS, INC.

John J. Reed
Chairman and Chief Executive Officer

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D.P.U. 07-50

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

Comments Prepared by John J. Reed on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company

EXECUTIVE SUMMARY

John J Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors ("CEA") has prepared comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company ("The Companies") to address selected issues raised in the DPU June 22 Order.

Mr. Reed's comments provide: (1) an overview of regulated ratemaking for electric and gas distribution companies; (2) a summary of ratemaking practices; (3) a description of base revenue adjustment mechanisms, which are commonly referred to in the industry as "decoupling mechanisms;" (4) a discussion of the reasons that decoupling measures have been implemented by gas and electric distribution companies throughout the US; (5) a discussion of cost tracking measures; (6) a description of features and elements of well-designed decoupling measures; (7) a series of recommendations on transitioning from the current Massachusetts ratemaking practice to ratemaking practices that include decoupling measures; and (8) a discussion of the value that the stock market places on decoupling and cost tracking measures.

In summary of Mr. Reed's comments, fundamentally, decoupling is a mechanism to collect a revenue target. These revenue targets should be determined in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would occur as a result of expanded energy efficiency efforts. Key to allowing utilities a reasonable opportunity to earn a fair rate of return is the principle that the revenue targets must account for yearly changes in expense–related and rate base-related costs.

Finally, decoupling mechanisms are being implemented by utilities across the country. Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

D.P.U. 07-50

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

Comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company

Prepared by John J. Reed

I. INTRODUCTION

By Order dated June 22, 2007, the Department of Public Utilities ("DPU") opened an inquiry[1] to investigate rate structures and revenue recovery mechanisms that may reduce barriers and disincentives to the efficient deployment of demand resources in Massachusetts. The June 22 Order included a straw proposal for a base revenue adjustment mechanism that is intended to sever the link between electric and gas companies' revenues and sales and, instead ties company revenues to the number of customers served. The June 22 Order also included a request for comments on the elements of the straw proposal, and a further request to address thirteen specific questions.

These comments have been prepared by John J Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors[2] ("CEA") on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company ("The Companies") to address selected issues raised in the DPU June 22 Order. Specifically, these comments will provide:

- An overview of regulated ratemaking for electric and gas distribution companies;
- A summary of the circumstances that have preceded the Department decision to consider implementing base revenue adjustment mechanisms, which are commonly referred to in the industry as "decoupling mechanisms;"

[1] Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources., Docket No. D.P.U. 07-50

[2] Mr. Reed's resume is included as Attachment A to these comments.

- A description of decoupling measures and a discussion of the reasons that decoupling measures have been implemented by gas and electric distribution companies throughout the US;
- A description of cost tracking measures[3] and a discussion of the reasons that cost tracking measures have been implemented by electric and gas distribution companies throughout the US;
- A high level description of features and elements of well-designed decoupling measures;
- A series of recommendations on short run and long run regulatory structures for transitioning from the current Massachusetts ratemaking practice to the new ratemaking practice, which includes decoupling measures; and
- A discussion of the value that the stock market places on decoupling and cost tracking measures.

To summarize my comments, fundamentally, decoupling is a mechanism to collect a revenue target. These revenue targets should be determined in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would occur as a result of expanded energy efficiency efforts.[4] Key to allowing utilities a reasonable opportunity to earn a fair rate of return is the principle that the revenue targets must account for yearly changes in expense–related and rate base-related costs. Finally, decoupling mechanisms are being implemented by utilities across the country.[5] Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

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[3] "Cost tracking measures" is a term that includes cost adjustment mechanisms, such as Electric Default Service tracker, Cost of Gas cost tracker, Pension/PBOP cost tracker, Low income discount cost trackers, Transmission Cost trackers, Transition Cost trackers, DSM cost trackers, Environmental Response Cost trackers, infrastructure replacement cost trackers. Cost tracking measures will also refer to price-cap indices and other rate plans.

[4] Similar conditions have been experienced by Massachusetts gas utilities and to a lesser extent electric utilities in the recent past. See, for example Comments Prepared by James D. Simpson, Concentric Energy Advisors in this proceeding, Attachments B and C.

[5] See, for example Comments Prepared by James D. Simpson, Concentric Energy Advisors in this proceeding, Attachments D and E.

II. STATEMENT OF THE ISSUE

As stated in the June 22 Order, the Department has opened this investigation to identify ratemaking practices that will improve the alignment between (1) important state, regional, and national energy policy objectives and (2) incentives that influence the behavior of Massachusetts electric and natural gas utilities. The June 22, 2007 Order identifies these state, regional, and national energy policy objectives:

- Promote the most efficient use of society's resources.
- Lower customer bills through increased end-use efficiency.
- Enhance the price-responsiveness of wholesale electricity markets.
- Mitigate the social and economic risks associated with climate change.
- Minimize the environmental impacts of energy production, transportation, and use.

Under current ratemaking practices in Massachusetts, utilities are financially harmed by reduced sales, because sales are directly linked to revenues and earnings. Since the efficient deployment of demand resources, such as energy efficiency measures, demand response programs, and distributed resources results in reduced sales for electric and gas utilities, the current incentive system that is embedded in Massachusetts ratemaking practices is in conflict with the Massachusetts energy policy objective of promoting efficient energy use.

The Department's Straw Proposal base revenue adjustment mechanism is a laudable effort that serves to advance the discussion of ratemaking practices in Massachusetts and decoupling within the context of Massachusetts ratemaking. These comments include recommendations for several enhancements and alterations that build on the Straw Proposal to ensure that (1) Massachusetts utilities will be neutral to state energy policy directives that result in reduced sales and will therefore be positioned to be active supporters of the Commonwealth's energy efficiency policies; (2) Massachusetts utilities are allowed a reasonable opportunity to earn a fair rate of return; and (3) there is a proper and appropriate consideration of the Department's decoupling design principles.[6]

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[6] These principles, listed in the June 22 Order, pages 11 and 12 are to meet or appropriately balance the needs to:
- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives;

- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources;
- meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs;
- meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design;
- be consistent with Department precedent related to rate continuity, fairness, and earnings stability;
- appropriately balance the risks borne by customers and those borne by shareholders;
- advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden;
- be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable; and
- be simple, easily understood, and transparent.

III. REGULATED RATEMAKING

A. INTRODUCTION

Decoupling measures are departures from traditional cost of service / rate of return regulated ratemaking. Therefore, justification and support for decoupling measures starts with an understanding of the key elements of traditional regulated ratemaking, and an identification of situations and circumstances under which traditional ratemaking practices create incentives and disincentives that conflict with energy policy objectives. In this section, I will describe and explain (1) traditional ratemaking, (2) revenue-related and cost-related modifications to traditional ratemaking, and (3) why a combination of revenue-related and cost-related modifications to traditional ratemaking is necessary to support and protect the needs and interests of customers, regulators and utilities and to promote important state energy policies.

B. FUNDAMENTALS OF TRADITIONAL RATEMAKING

Traditional cost of service / rate of return regulation, as practiced by state regulatory agencies including the DPU, is based on an analysis of a utility's cost of doing business in a recent historical period ("Test Year") to determine the level of revenues ("Revenue Requirement") that would have allowed the utility a reasonable opportunity to earn a fair rate of return in that historical period. The revenue requirement consists of (1) expenses, (2) return <u>of</u> investment in plant (depreciation), (3) return <u>on</u> investment in plant, and (4) taxes. Typically, state regulators allow adjustments to test year data to ensure that the historical costs are representative of the costs that are likely to be experienced in the future period when the new approved rates will take effect.[7] The return on investment component of the revenue requirement accounts for the cost of debt that the utility has issued and the cost of equity, which is determined by analysis to be the return that will allow the utility to maintain credit and attract investors.[8]

In simple terms, the rates that are charged to customers are determined by dividing the revenue requirement by the units of sales; the units of sales are determined in a manner that is intended to be representative of the sales that are likely to be experienced in the period when the new rates will take

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7 These adjustments can include "known and measurable" adjustments, future test year projections, or some combination of the two.

8 The principles for establishing the reasonable return on equity have been set in two landmark decisions of the U.S. Supreme Court, Bluefield Water Works & Improvement Co. v. Public Service Company of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944)

effect. The detailed determination of the billed rates involves assigning the appropriate and fair portion of the total revenue requirement to each of the rate classes that receives service from the company, and by further separating the class revenue requirement into the portions that will be recovered from each of the types of units of sales – billing determinants - that apply to that rate class, e.g. customer, commodity or energy, and demand. Finally, customer charge rates, volumetric or energy rates and demand rates to be billed to customers in each rate class are calculated.

C. CHALLENGES OF TRADITIONAL RATEMAKING

Traditional ratemaking, which is based on an examination of historical utility costs and billing determinants, is designed to allow regulated utilities to earn a fair rate of return if the conditions that affect utility revenues and costs are generally similar and consistent between the historical test year period and the future periods when the rates that are determined from the test year data will be charged. Traditional ratemaking <u>may</u> <u>not</u> produce reasonable results when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are very different from the conditions that were experienced during the test year.

Several common modifications and adjustments to traditional ratemaking are designed to address cost-related and revenue-related situations where future conditions are likely to be different from test year conditions.

1. <u>Cost-related Modifications to Traditional Ratemaking</u>

a. <u>Cost trackers</u>

Typically, cost-related modifications to traditional ratemaking are designed to recover the costs of specific activities or expense items with the following characteristics: (1) the costs are large, relative to the utility's total costs, (2) the costs are subject to significant unpredictable fluctuations, and (3) the costs are largely outside of the utility's control. The most common of these cost-related ratemaking modifications are cost tracking mechanisms, which recover the costs of a specific activity or expense item through a dedicated rate that is set and revised on a regular basis according to simplified procedures and an expedited schedule, in contrast to the procedures and schedules of base rate proceedings. Total utility rates billed to customers are the combination of base rates, which are determined according to traditional ratemaking practices, and cost tracking charges.

Typically, cost tracking mechanisms reconcile actual costs incurred for the specific activity in a period – e.g. annually, semi-annually, or quarterly – with cost tracker revenues billed in the same period. Revenues in excess of actual costs are returned to customers in a future period, and revenue shortfalls are recovered from customers in a future period.

Common cost tracking mechanisms employed by US electric and gas utilities include the following:

- Fuel cost / power cost / default service cost
- Gas costs
- Pension and PBOP[9] expense
- Bad debt related to energy supply
- Infrastructure replacement costs
- Environmental response costs
- DSM program expense[10]

Even gas cost trackers, now in effect for almost all gas utilities in the US,[11] are a relatively recent modification to traditional ratemaking. Until the early 1970s, FPC[12] regulation of gas commodity prices resulted in stable and predictable gas costs; it was common for gas utilities to recover gas supply costs[13] through traditional ratemaking practices. However, in the late 1970's, regulation of gas prices at the well head was partially lifted to stimulate exploration and production activities through competitive market forces, and as a result, wellhead commodity costs began to fluctuate in response to short term and long term shifts in demand and supply for gas. With gas utilities experiencing large fluctuations in gas supply costs that were beyond their control, traditional ratemaking procedures no longer functioned well to set rates, which resulted in widespread implementation of gas cost trackers.

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9 Post-retirement Other than Pension.

10 The reduction in net revenues associated with utility DSM activities is typically included in DSM cost trackers.

11 Notable exceptions: (1) Companies that do not incur gas supply costs *e.g.* AGL Georgia; due to operations in unbundled retail access jurisdictions, where customers receive gas supply service from third party suppliers, and therefore do not require gas cost trackers. (2) Until recently, Vermont legislation has prohibited Vermont utilities from implementing gas cost or electric power cost trackers; Vermont utilities that implement Alternative Rate Plans are allowed to include gas or electric power trackers in the ARP.

12 Federal Power Commission, the predecessor to the Federal Energy Regulatory Commission. The Natural Gas Act of 1938 gave the FPC regulatory authority over wellhead prices; the Natural Gas Policy Act of 1978 set limits on wellhead prices; these price controls were lifted by The Natural Gas Wellhead Decontrol Act of 1989. In addition, utilities began to obtain direct access to market supplies as a result of FERC order 436, in 1985.

13 At the time, interstate pipelines provided bundled supply and pipeline transportation service to their utility customers under FERC-regulated demand and commodity rates.

i Regulatory Basis for Cost Tracker Mechanisms

Cost trackers are important ratemaking tools for specific, limited categories of costs that, in comparison to traditional cost of service/ROR ratemaking: (1) are more equitable for both customers and utilities; (2) produce more accurate and timely price signals, (3) result in more stable utility earnings; (4) result in more stable prices to customers over the long run, and (5) eliminate the need for frequent and contentious regulatory proceedings.

b. Index-based Rate Plans

A different form of cost-related modifications to traditional ratemaking includes index-based rate plans, such as those included in PBR[14] plans approved by the Department for NSTAR Electric Company, National Grid, Bay State Gas Company, Keyspan Energy Delivery New England (Boston Gas), The Berkshire Gas Company, and Blackstone Gas Company. Utilities that have implemented an index-based rate plan are authorized to change base rates on an annual basis according to a Department-approved price cap formula. Typical Department-approved price cap formulas include a measure of an annual inflation rate, a productivity offset factor ("X") and an exogenous cost factor ("Z"):

$$\%\Delta\text{Price Cap} = \%\Delta\text{Price Index} - X + Z$$[15]

Even though index-based rate plans focus on the rates, which are a principal determinant of overall revenues, they can be categorized as cost-related plans since they effectively serve as a surrogate for a redetermination of the utility's total cost of service.[16]

i Regulatory Basis for Index-based Rate Plans

Index-based rate plans are innovative ratemaking tools that: (1) provide incentives to the utility to increase economic efficiency and improve cost controls; (2) produce rates that are more stable and

14 As used in these comments, "PBR" refers to the following components of rate plans that have been approved by the Department: (1) index-based rate cap mechanisms; (2) service quality measures with a penalty structure; and (3) and Earnings Sharing Mechanism

15 For example, the individual elements of Bay State Gas Company's price cap formula are determined as follows:

- $\%\Delta$Price Index $= (\text{GDP-PI}_t / \text{GDP-PI}_{t-1}) - 1$
- X = Productivity Offset = [(Total Factor Productivity $\text{Trend}^{\text{NE Gas Distributors}}$ – $\text{TFPTrend}^{\text{US}}$) + (Input Price Trend^{US} - Input Price $\text{Trend}^{\text{IND}}$)] + Consumer Dividend Factor; where Total Factor Productivity is defined as output per unit of total factor input
- Z = Exogenous Cost Factor

16 The Department's price cap rate plans also include incentive structures to reward superior performance, in addition to re-determining a utility's total cost of service.

lower over an extended period of time, and (3) reduce the administrative burden of regulatory proceedings for all parties, which reduces costs that are ultimately recovered from customers.

2. Revenue-related Modifications to Traditional Ratemaking

a. Introduction and Background

Decoupling measures are an increasingly common category of revenue-related modifications to traditional ratemaking.[17] Decoupling measures address revenue-related shortcomings with traditional ratemaking in the same way that cost trackers and index-based rate mechanisms address cost-related issues in traditional ratemaking. Specifically, as a result of conservation and other demand response efforts, the conditions that will impact utility revenues in the future when a specific set of base rates will be charged are very likely to be different from the conditions that were experienced during the test year that was used to determine that set of base rates.

b. History of Decoupling Measures

In recent years many gas utilities and several electric utilities have implemented decoupling measures to break the link between sales and utility earnings; the current interest in decoupling has been a response by electric and gas utilities and their regulators to (1) the long term trend of declining gas use per customer that has been experienced nationwide, (2) a long term trend of declining electric energy demand per customer that has been experienced by some electric utilities due to circumstances that are region-specific,[18] (3) electric and gas customer response in 2005 to 2006 to spikes in the price of energy; and (4) plans to expand utility-driven conservation programs. These circumstances have caused utility revenues to be less than they otherwise would have been; recent efforts to expand energy efficiency programs will continue these trends into the future.

California utilities first implemented decoupling mechanisms over two decades ago; California gas and electric decoupling mechanisms were implemented as early as 1978 and 1982, respectively. The California Public Utilities Commission ("CPUC") explained in a 1981 PG&E order that "…the adoption of an ERAM [Electric Revenue Adjustment Mechanism] … will eliminate any

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17 Other common revenue-related modifications include weather normalization adjustments and non-firm revenue adjustments.

18 For example, some electric utilities have been experiencing reductions in the number of residential customers and use per customer as a result of price-induced fuel switching.

disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned.[19]" Although the CPUC suspended the decoupling mechanisms in the late 1990s, new mechanisms have been put in place for California utilities in response to legislation passed in 2001 requiring that "The Commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations."[20,21]

c. Elements of Decoupling

Decoupling mechanisms are designed to decouple revenues from sales. Traditional ratemaking establishes rates for delivery customers so that as the quantity delivered increases (or decreases) so do the utility revenues. In general terms, decoupling mechanisms serve to adjust utility rates in a future period to account for differences in revenues received in the most recent historical period, compared to test year revenues; a revenue requirement target is compared to actual revenues and the revenue difference is recovered from or returned to customers in a future period.

In several jurisdictions, specific features of decoupling measures have been introduced to allow decoupling to function more fairly and to better meet the goals and objectives of the parties. A common enhancement to the standard decoupling approach is to adjust test year revenue targets to account for post-test year changes in the utility's costs. Decoupling as implemented in California is an example of this approach; the CPUC sets revenue requirements for each year of the rate plan, based on a number of factors and analyses, including cost trends, inflation factors, and plant addition plans.

i Regulatory Basis for Decoupling

Although decoupling mechanisms have been in effect since the late 1970s, there has been a recent increase in the number of utilities that have adopted decoupling measures in response to the cumulative impact of decades of energy efficiency measures on customer energy demand and

19 Decision 93887, dated December 30, 1981
20 Public Utilities Code; Section 739.10, April 2001
21 A detailed description and discussion of California decoupling mechanisms is provided in comments prepared by L. Kaufman of Pacific Econometrics Group in this proceeding.

dramatic customer responses to energy price spikes.[22] In the regulatory reviews of these recently-adopted decoupling measures, the parties to these proceedings have identified the following benefits of decoupling:

- Decoupling measures align utility's interest with public policy goals – shareholders are not penalized by the effect of conservation-related programs.
- Decoupling measures align the customer's interest in conserving with the utility's interest in recovering its costs.
- Decoupling measures reduce volatility and unpredictability of customer bills.
- Decoupling measures reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability.
- Decoupling measures eliminate need for the utility to file frequent rate cases to compensate for declining use that is the result of customer conservation.

3. Modifications to Traditional Ratemaking: Summary and Conclusions

Decoupling mechanisms are examples of revenue-related modifications to traditional ratemaking practices that are increasingly common nationwide, implemented in response to local state and federal policy objectives and utility-experienced declining demand and revenue per customer. Cost trackers and index-based rate plans are examples of common cost-related modifications to traditional ratemaking practices. The circumstances that justify and support the implementation of revenue-related and cost-related modifications are very different. Specifically, revenue-related and cost-related modifications to traditional ratemaking are not substitutes for one another. To the contrary, these two categories of modifications are compatible with each other and serve to address very different regulatory and policy objectives. If the Department were to implement revenue-related modifications to traditional ratemaking without allowing cost-related modifications (or the converse) it would have the following negative implications for utilities and their customers:

- Rapid and large scale deployment of customer-sited, cost-effective demand resources is likely to be hindered, contrary to Commonwealth of Massachusetts' policy directives and objectives.
- Rates to customers are likely to be based on costs of certain utility activities that are significantly greater than or less than the actual cost of those activities from time to time.

[22] Additional discussion of these decoupling measures is included in Comments Prepared by James D. Simpson, Concentric Energy Advisors, in this proceeding

- Changes to rates ordered in base rate proceedings are likely to be subject to significant volatility from case to case.
- The frequency of base rate proceedings are likely to increase, which imposes greater administrative burdens and expense on all parties: the Department, the Office of the Attorney General, other intervenor groups, and utilities.[23]

[23] Ultimately, greater administrative costs to all of these groups are paid for by the Massachusetts utility customers.

IV. RECOMMENDATIONS FOR THE IMPLEMENTATION OF DECOUPLING MEASURES BY MASSACHUSETTS GAS AND ELECTRIC UTILITIES

A. INTRODUCTION

The Department has stated that a decoupling mechanism should create an appropriate balance among the following principles and objectives:

- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives;
- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources;
- meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs;
- meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design;
- be consistent with Department precedent related to rate continuity, fairness, and earnings stability;
- appropriately balance the risks borne by customers and those borne by shareholders;
- advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden;
- be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable; and
- be simple, easily understood, and transparent.

I have identified an additional decoupling design principle that has important implications for the implementation of decoupling in Massachusetts:

- Consistent with the need to balance all other decoupling design principles, decoupling should be implemented as expeditiously as possible and reasonable, in furtherance of the Commonwealth's energy efficiency directives and objectives.

This added principle introduces an appropriate sense of urgency to the Department's principle that a decoupling measure should "better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives." This additional principle is in keeping with Governor Patrick's announced plans to offset the state's annual increases in electricity demand with equivalent energy-efficiency and conservation measures by 2010 by requiring utilities to pay for and otherwise promote cost-effective conservation efforts, among other actions.

In the remainder of this section, I will describe and explain my recommendations for the implementation of decoupling in Massachusetts, which are based on and consistent with the Department's articulated principles and objectives together with the principle that I have added.

B. CEA Recommendations for Implementation of a Decoupling Mechanism

I have developed several recommendations concerning the implementation of decoupling measures in Massachusetts that expand upon or modify some details of the Department's Straw Proposal and the accompanying explanation and discussion in the June 22 Order. These recommendations are based on my extensive experience with market expectations and requirements, decoupling measures, rate design, cost of service and allocated cost studies.

1. Recommendation 1: Expeditious implementation of decoupling, which is directly tied to expedient implementation of utility-sponsored energy efficiency efforts, can be achieved for all utilities with minimal delay.

a. Introduction: The Department's Prerequisite for Implementation of Decoupling

The June 22 Order states that a utility must complete a base rate proceeding as a prerequisite for establishing a decoupling mechanism,[24] the base rate proceeding would include the standard detailed examination of a utility's cost of service, cost allocation and rate design. This requirement will unnecessarily delay full adoption of the Commonwealth's energy efficiency and demand resource initiatives because (1) as a practical matter, the Department, the AG, other intervening parties, and the utilities lack the necessary resources to prepare and process base rate filings if all Massachusetts gas and electric utilities made those filings at the same time; and (2) several gas and electric utilities have rate plans in place that have several years remaining until they can file a base rate case. Although there are legal matters included in this issue that I will not address, I will state that regulatory policy considerations would argue against early termination of Commission-approved rate plans, even in the context of implementing decoupling mechanisms.

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24 June 22 Order, page 14.

b. Discussion

i The Department's proposed decoupling prerequisite comes with significant scheduling and administrative burdens

The Department's prerequisite would require a significant and time consuming deployment of resources by every Massachusetts utility to: (1) create "rate case quality" cost of service data, (2) prepare an allocated cost study, (3) prepare a marginal cost study, (4) design a decoupling mechanism in accordance with the Department's directives from this proceeding, (5) design rates, (6) prepare testimony in support of the rate case filing, and (7) prepare all filing requirements. In recognition of the level of effort that would be required by utilities to prepare base rate filings and that would be required by the Department, the AG and other parties to review the filings, it is not feasible for all utilities to file at the same time. Even if the utilities could be organized to proceed through the Department's rate case process in as few as three groups, it is unlikely that the entire process could be completed for all utilities in less than 30 months,[25] based on the time for: (1) each utility to prepare a filing; (2) the Department, the AG and other parties to review the utility filings, and (3) the Department to prepare a final order.

ii The Department's proposed decoupling prerequisite is not necessary for the full implementation of decoupling in Massachusetts

The Department's requirement that a base rate case must precede implementation of a decoupling measure is unnecessary and is in conflict with the ambitious nature of the Commonwealth's announced objective to offset the state's annual increases in electricity demand with equivalent energy-efficiency and conservation measures by 2010, and the recognized necessity of having the full support and cooperation of the state's utilities in order to achieve those objectives.

[25] The estimated 30 month period is based on the following assumptions:

• Complete 07-50	3 months
• 1st group prepares and files rate cases	6 months
• 1st group suspension periods	6 months
• 2nd group reviews 1st group orders, completes preparation of and files rate cases	2 months
• 2nd group suspension periods	6 months
• 3rd group reviews orders, completes preparation of and files rate cases	2 months
• 3rd group suspension periods	6 months
• Total	31 months

The Department's concern that the current base rates may be producing distorted price signals is not warranted and should not serve as a barrier to the beneficial impact of energy efficiency programs in Massachusetts. To the contrary, the currently effective rates for all Massachusetts utilities have been determined to be just and reasonable by the Department. There is no justification for formulating requirements, procedures and schedules in this proceeding based on the assumption that current rates may not be just and reasonable; that assumption would only serve to put the timely implementation of beneficial energy efficiency programs at risk.

If the Department's proposed decoupling prerequisite is based on an unspoken concern by the Department that the current rates are producing earnings in excess of the allowed return on equity ("unjust enrichment"), I recommend that this concern can be addressed by implementing an Earnings Sharing Mechanism ("ESM") for those companies that do not already have a currently effective ESM.

c. <u>Short Run Alternative to the Department's Requirement of a Base Rate Case as a Prerequisite of Decoupling</u>

To ensure expedited development of the Commonwealth's energy efficiency and conservation programs, and full utility commitment to those programs, I recommend that the Department allow utilities to file decoupling measures that are consistent with the Department's Straw Proposal concept of determining a target revenue, immediately upon the conclusion of this proceeding. I further recommend that each utility be allowed to propose a basis for determining revenue targets for the following specific individual company circumstances.

<u>Circumstance 1:</u> As further discussed in the next section, utilities that have a currently effective rate plan may elect to reflect their approved index-based rate plan adjustments in the calculation of target revenues for each year that the decoupling mechanism is in effect until the conclusion of the rate plan.

<u>Circumstance 2:</u> Companies that are near the end of the term of a rate plan, or utilities that do not have a currently effective rate plan should be allowed to calculate revenue targets by alternative approaches other than the most recent rate case (if the utility does not have a currently effective rate plan) or other than the current rate plan (if the rate plan is near date of termination).

In addition to the determination of revenue targets, utilities should be allowed to continue to utilize cost tracker adjustments for currently effective mechanisms; the costs and revenues from these cost trackers should be excluded from the decoupling mechanism calculations.

i Summary of Basis for Recommended Short Run Alternative

This recommended alternative is a reasonable and practical balancing of the Department's decoupling design and implementation principles. Fundamentally, decoupling is a mechanism to collect a revenue target; each utility's currently effective rates – which reflect the cumulative adjustment of any index-based rate mechanism to the base rates determined in a rate case proceeding - serve as a reasonable basis for determining that revenue target.[26] The Department's stated desire to reset or re-examine current base rates may be driven by a concern of unjust enrichment, which can be addressed by implementing an ESM, with the sharing collar based on the allowed ROE from the most recent rate case. The perspective that I recommend allows for the most expeditious implementation of decoupling measures, and therefore the most expeditious adoption of aggressive energy efficiency goals and objectives.

2. Recommendation 2: Decoupling mechanisms should allow for the continuation of all currently effective cost trackers, index-based rate plans, and other cost-related modifications to traditional ratemaking.

a. The Department's Statements Concerning Cost-related Ratemaking Modifications

The June 22 Order states that, "(t)he continued need for or form of such fully-reconciling charges in the context of a base revenue adjustment mechanism would be addressed in individual company base rate proceedings, in consideration of their impact on company cost control incentives, simplicity, and related principles."[27] The June 22 Order also states that, "(u)pon the implementation of a base revenue adjustment mechanism, a company's current PBR plan would no longer be in effect."[28]

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[26] Currently effective rates may not be a reasonable basis for determining a revenue target in situations such as those defined in Circumstances 1 and 2, which would therefore requiring flexibility in implementation to allow for utilities to make alternative proposals.
[27] June 22 Order, Page 13, footnote 9.
[28] June 22 Order, Page 18

b. Discussion

The suggestion that fully-reconciling charges (i.e. cost trackers) may not be compatible with decoupling is contrary to the basis and justification for cost trackers. As I have explained in Section III. Regulated Ratemaking, to these comments, cost trackers and decoupling mechanisms are consistent with each other, and are appropriate modifications to traditional ratemaking practice. The conditions that give rise to the implementation of cost trackers, i.e. unpredictability and volatility of costs that are not within the utility's control, remain a sound basis for retaining cost trackers after decoupling mechanisms have been put in place. Decoupling mechanisms, by design, are intended to ensure that a utility's revenues are not diminished by factors such as policies that promote conservation. However, decoupling mechanisms do not offer customers protection from rates that exceed the current cost to serve due to a downturn in gas prices; decoupling mechanisms also do not provide a utility protection from increased pension funding requirements stemming from a downturn in the stock market, for example.

Also, the Department's statement that a company's PBR plan would no longer be in effect upon implementation of a decoupling mechanism should be clarified to indicate that if a utility implements a decoupling mechanism without first completing a base rate case, consistent with Recommendation 1, that the Department would not prematurely terminate the index-based rate mechanism in a currently effective PBR plan.

In addition, the Department's statement on PBR plans, especially in combination with the statements about cost trackers, can be interpreted to indicate that the Department is predisposed to eliminating many if not all cost trackers and index-based rate adjustments. As also discussed earlier, index-based rate plans and decoupling mechanisms are completely consistent with each other; and a combination of cost-based and revenue based-modifications are necessary to address conditions that lead to challenges for traditional ratemaking, such as the current utility experience – steadily increasing costs, declining demand per customer and planned expansions in utility-driven energy efficiency programs in Massachusetts.

Decoupling mechanisms allow utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would be triggered by expanded energy efficiency efforts. Index-based rate adjustments allow utilities a reasonable opportunity to earn a fair rate of return in conditions of overall increasing utility costs. If the Department were to discontinue cost trackers or index-based rate adjustments upon implementation of decoupling measures, utilities' ability to earn a fair rate of return would be impaired. Utilities would be subject to cost-related earnings volatility that is comparable to, and may even be greater than the revenue-related earnings volatility that decoupling is designed to address.

Also, it is my recommendation that the Department carefully consider the likely financial market response to the elimination of cost trackers or index-based rate adjustments, in the context of implementing decoupling measures. Market analysts that follow utilities are familiar with and respond favorably to cost trackers and PBR rate plans; Department actions to terminate any component of these cost-related ratemaking modifications would be viewed with concern, which may impact analyst recommendations and negatively affect the cost of capital for Massachusetts utilities. This is an especially critical consideration during a period that many Massachusetts utilities have significant non-revenue generating capital replacement programs to address the safety and reliability of their transmission and distribution systems.

3. Recommendation 3: The Department's long run approach to decoupling should reflect a comprehensive perspective on utility costs and revenues that provides incentives that are supportive of the Department's goals and objectives..

a. Introduction and Statement of the Issue

Recommendation 1 is a regulatory policy strategy that is appropriate for the short run; it is designed to ensure expedited implementation of decoupling mechanisms, which will enable expedited implementation of the new energy efficiency programs. Recommendation 3 recognizes that a long run decoupling approach is an appropriate opportunity to address additional regulatory issues that may be overly complicating to deal with in the initial short run filings, because to do so may delay the initial implementation of decoupling. I recommend that the Department should allow each utility to propose a long run decoupling approach that fits the needs and situation facing that utility and that is consistent with the following general decoupling guidelines:

- The methodology used to determine target revenue requirements should account for the effects on utility expenses of increases in the prices of goods and services used by utilities.

- The methodology used to determine target revenue requirements should account for the cumulative impact of capital spending on rate base and depreciation expense.
- The methodology used to determine target revenue requirements should also allow for large exogenous changes in costs.
- Utilities should have flexibility in determining the rate classes that the decoupling measures are applied to.
- The period of a decoupling rate plan should be of an appropriate length to: (a) provide for efficiencies and cost savings related to rate case expenses, (b) allow utilities to benefit from acting in a manner that is consistent with rate plan incentives and to experience the impacts of acting in a manner that is in conflict with rate plan incentives, (c) allow for regulatory reviews of utility rates and practices at appropriate intervals.
- During the period of each long term rate plan, utilities should have flexibility, within limits, in determining the allocation of revenue requirements to rate classes, and in determining the rate design (customer charge, volumetric charges, demand charges) to recover the target revenue requirement.

In addition, long run decoupling approaches should be consistent with decoupling principles that apply as well to the short run:

- Consistent with short run decoupling, utilities should remain neutral to energy efficiency efforts; current disincentives to utility-driven conservation programs should be removed;
- To ensure against excessive over or under earnings, decoupling measures should include an Earnings Sharing Mechanism, and reasonably determined off ramps, to allow a utility to make a rate increase filing, or for the Department or the AG to require a filing to justify the existing rates;
- Rates and rate design should send appropriate and accurate price signals, while also promoting "Bonbright's rate design principles" of rate stability, continuity, fairness, etc.

b. <u>Discussion of Long Run Decoupling Guidelines</u>

The underlying principle of all of the guidelines listed above is to ensure that (a) Massachusetts utilities have a reasonable opportunity to earn a fair rate of return, (b) that customers of Massachusetts utilities are charged fair rates without unjust enrichment of the utility, (c) disincentives to utility-driven energy efficiency programs are eliminated, and (d) the regulatory review process is efficient and cost-effective. The long run decoupling guidelines that I have listed are similar to the short run guidelines with two key differences:

i The Department should allow utilities flexibility in designing long run decoupling approaches.

The short run guidelines are designed to provide for the expeditious elimination of disincentives to energy efficiency through the implementation of decoupling measures. The regulatory review of each utility's long run decoupling approach will be made as part of a base rate proceeding; the statutory suspension period will allow time for all parties to review each utility's proposal and to examine differences that would warrant different decoupling approaches for different utilities.

ii The Department should allow decoupling approaches that determine target revenue requirements in a manner that accounts for the cumulative impact of capital spending on rate base and depreciation expense during the period that a decoupling rate plan is in effect.

Utilities are typically engaged in long run, large infrastructure replacement programs,[29] which expose them to another shortfall of traditional ratemaking. Traditional ratemaking does not account for the impact on utility earnings of infrastructure replacement projects. In undertaking an extended infrastructure replacement program[30] a utility is incurring significant additional depreciation expense and capital costs associated with each year's incremental investment in infrastructure that is not reflected in the currently effective rates. The effect of the incremental infrastructure investment on a utility's revenue deficiency continues to accumulate, and will lead to increasing earnings erosion, until the utility files a new base rate case.

c. Long Run Ratemaking Framework

I recommend that a long run ratemaking process be established that would be applied to base rate filings starting with each utility's first base rate case filing after implementation of the initial (short run) decoupling mechanism. To ensure that the Department's decoupling design principles are met, the long term ratemaking process should include the following considerations:

- The process used to set base rates should remain unchanged from the Department's current standards and practices; initial base rates should be determined on the basis of historic and/or future test year data.

[29] For example, to meet objectives related to system safety or reliability.
[30] For example, Massachusetts gas utilities may have enacted programs to replace bare steel and cast iron distribution mains for safety and reliability reasons.

- The overall level of rates for each rate class should be determined by reference to an allocated cost study, and the base rates billed to customers would be determined based on the Department's articulated rate design standards.
- The decoupling process should allow for target revenues that are updated from test year levels to reflect increases in utility expenses.[31]
- Costs that are volatile and not subject to utility control, such as power or gas costs and pension and PBOP expense should be recovered through reconciling mechanisms, as they are currently.
- Provisions should be developed to address the costs of plant investment programs that meet Department-established standards to recover the costs of infrastructure replacement programs.[32]
- To decouple revenue and earnings from actual energy demand, actual revenues in a year should be reconciled with the appropriately developed revenue target for that year. That is, the revenue targets should be established according to rate plan formulas or other reasonable procedures[33] to reflect current expense levels and plant investment.

I further recommend that the Department should establish a general framework for long-run ratemaking and that utilities should be allowed to make specific proposals, based on the Department's framework, when each utility files its first base rate case after the implementation of short run decoupling measures.

d. Comments on the Long Run Framework

My recommendation that the long run ratemaking process should include provisions to address the cost of plant investment programs is necessary to remove disincentives to investing in plant for safety and reliability that are present in traditional ratemaking. The safe and reliable operation of all utility distribution systems requires adequate (and sometimes increased) system investment. In specific circumstances, utilities have infrastructure challenges to meeting safety and reliability requirements that need to be addressed. The Department's long run framework should allow for company-specific proposals on capital programs to address those specific challenges.

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31 The price cap formula that is currently used in Massachusetts PBR rate plans, which includes a measure of an annual inflation rate, a productivity offset factor ("X") and an exogenous cost factor ("Z") is an example of a process that would allow for "target revenues (to be) updated from test year levels to reflect increases in utility expenses."

32 The revenue requirement impacts of such programs, which are typically related to maintaining safe and reliable service to existing customers, are not adequately addressed by incremental growth-related revenues or by price cap rate formulas such as Massachusetts PBR rate plans

33 The approach used by several California utilities to determine revenue targets for all years of the rate plan using various methods to forecast and project cost levels is an example of a "reasonable procedure."

e. Examples of Long Run Decoupling–type Ratemaking Procedures

A number of utilities in the US have implemented plant investment cost tracking mechanisms to adjust rates on an annual basis to account for incremental changes in a utility's revenue requirement associated with incremental plant investment. These mechanisms are generally designed to remove the disincentives associated with targeted infrastructure investment for safety or reliability.

In the past several years, California utilities have re-implemented comprehensive ratemaking procedures in which projected revenue requirements are determined in rate case proceedings for every year of a multi-year rate plan, taking into account expected changes in expenses and rate base. Each year's forecast test year revenue requirement is reconciled with actual revenues; over-recoveries are returned to customers and under-recoveries are recovered from customers. Volatile uncontrollable costs, such as pension and PBOP expense, are recovered through reconciling cost tracker adjustments. The California ratemaking practice: (1) has eliminated disincentives to utility participation in California's aggressive energy efficiency programs; (2) ensures that rates are reflective of the forecast test year costs that the utility incurs, including costs that are volatile and unpredictable and costs related to additions to plant; (3) reduces volatility; and (4) allows utilities a reasonable opportunity to earn a fair rate of return.

I recommend that the California ratemaking practice be given careful consideration; the California process provides an appropriate balancing of the Department's decoupling principles and includes appropriate incentives for safe and reliable service.

V. INTERRELATIONSHIP BETWEEN DECOUPLING MEASURES, COMPANY ROE AND CAPITAL STRUCTURE

Rate structures designed to mitigate the effects of declining use per customer are becoming increasingly common. Members of the financial community view these measures as a logical response to the challenges facing (1) utilities striving to earn their allowed return; and (2) regulators seeking to make demand reduction a viable means for customers to reduce their bills.

It is therefore important to analyze how the financial community reacts to the approval of decoupling mechanisms vis-à-vis the relative valuation of the stock of the utility. Indeed it is investors' required returns that regulators estimate when setting utility rates. To the extent that decoupling affects investors' required returns, that effect should be reflected in rates, which raises the question of whether an explicit adjustment in ROE is warranted when decoupling is approved.

To date, there is no evidence suggesting that investors' required returns are reduced as a result of the approval of decoupling mechanisms. The recent expansion in the use of decoupling mechanisms is in response to significant market changes, and the policy responses to these changes, in the past few years. Specifically, fossil fuel price spikes have led to significant increases in utility rates, which have caused significant price-induced conservation. Additionally, concerns with energy security and climate change have given rise to policy initiatives designed to encourage further demand reductions. Notably, while the fossil-fuel price changes that led to all of these responses created significant revenue recovery risks for utilities, there was virtually no upward adjustment to allowed ROEs anywhere in the U.S. to reflect these higher risks. Decoupling mechanisms are an effective means to offset these incremental risks, but they certainly cannot be viewed as warranting a reduction in allowed returns when the recently-created risks they offset were never previously reflected in rates.

Furthermore, there is analytical and anecdotal evidence supporting the position that investors' required returns are unaffected by the implementation of decoupling measures. Though revenue decoupling clearly offsets the recently-identified risk that fixed costs will not be fully recovered due to declining use, it also eliminates the opportunity for any corresponding gains. As rate proceedings are based on assumptions of normal weather and forecasted customer consumption, aside from the recent trend of declining use per customer or the social goals of conservation, the gains and losses imparted by revenue decoupling mechanisms should in theory be a wash, ensuring only that forecasted revenues will be realized but not that authorized returns will necessarily be earned. The evidence does not show that investors are willing to accept lower returns in exchange for the company's enhanced ability to earn its return or to promote social conservation objectives. Correspondingly, the rating agencies will not upgrade the credit of a utility for the approval of a decoupling mechanism, but do state that a company without full revenue decoupling stands a greater risk of downgrade. For example, Moody's Investor Service stated in a June 2006, Special Report on Revenue Decoupling and Local Gas Distribution Companies that,

> *LDCs that have, or soon expect to have, RD [Revenue Decoupling] stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.*[34]

It is apparent that rating agencies view decoupling mechanisms as a means of maintaining the status quo in today's volatile utility environment. The implication is that some form of revenue stabilization is expected, and companies without such protection are subject to negative actions from the rating agencies.

To analyze whether the implementation of a full revenue decoupling mechanism measurably affects the investor's perception of risk as evidenced in a company's relative stock valuation, CEA performed an analysis to compare the price-to-book ("P/B") ratio of utilities that have received approval to implement decoupling mechanisms to the average P/B of a group of peer companies to test for any measurable change in relative valuations.[35] On average, the relative P/B of the utilities receiving approval to implement decoupling did not increase during the month following the approval, when compared to the month preceding the approval. Put another way, there is no evidence that the approval of decoupling reduces investors' required returns. The following charts illustrate the reaction of the stock price to news of the approval of a decoupling mechanism for the 30 days before and 30 days after the announcement, relative to the peer group average P/B ratio for both natural gas distribution and electric utilities:

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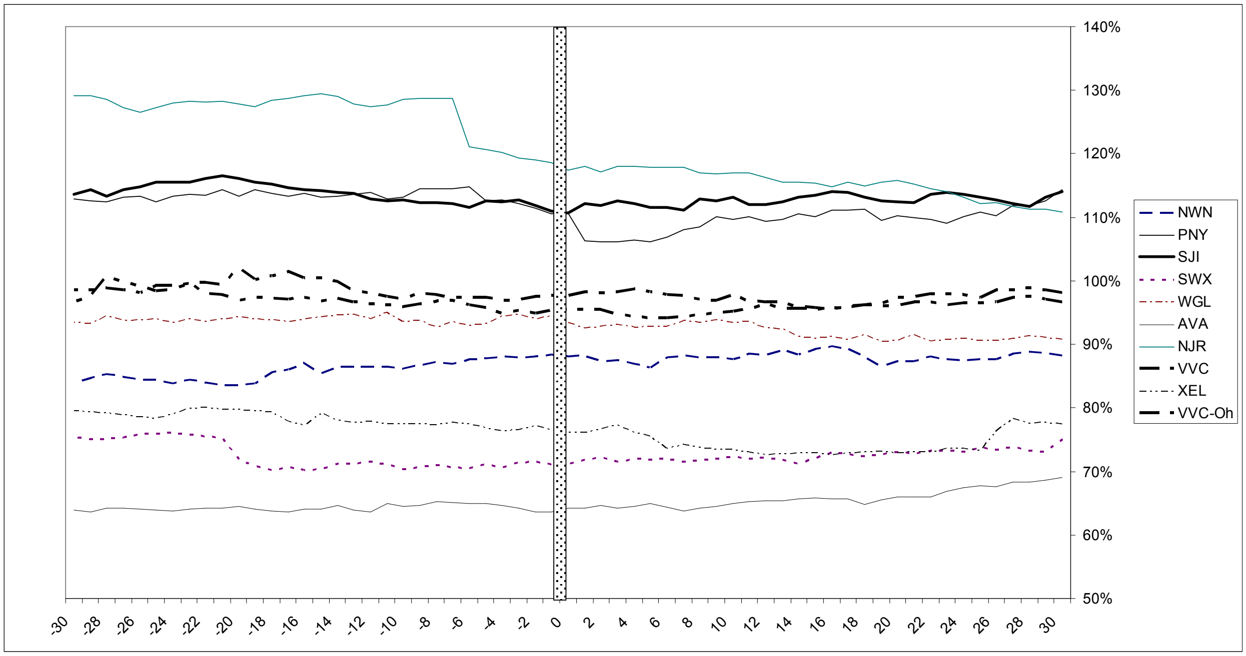
34 Moody's, Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings.

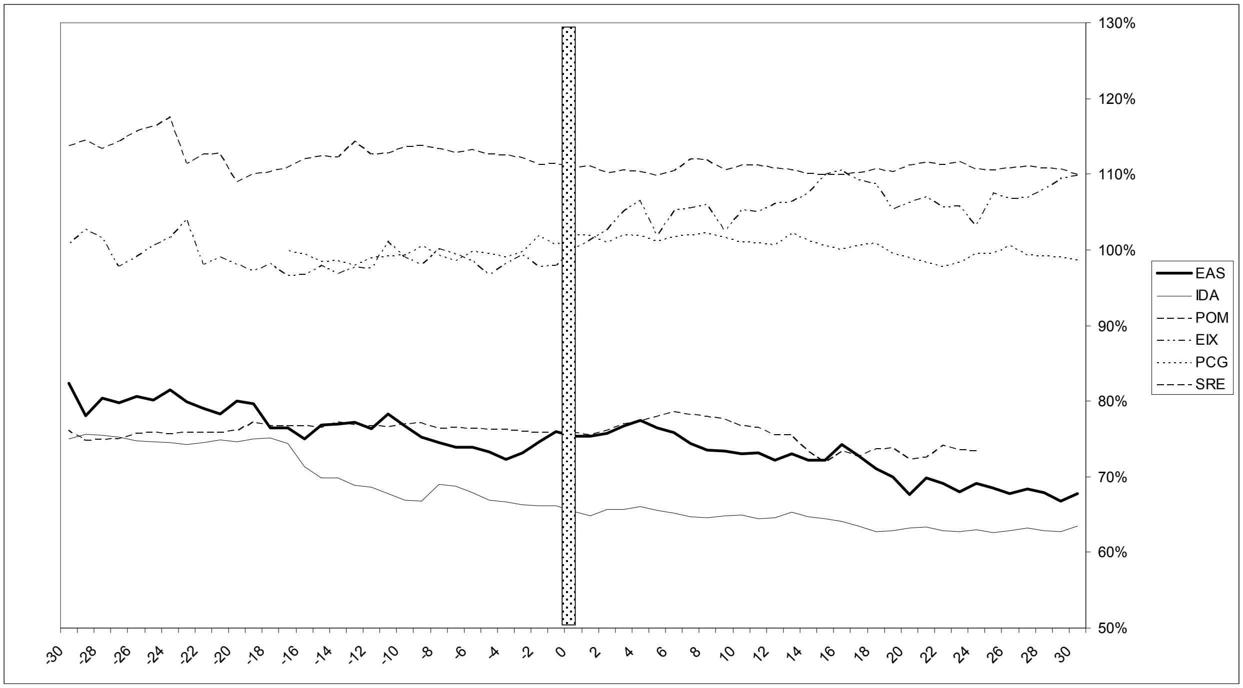
35 CEA's analysis controlled for general market movements by creating a P/B Index for all utilities; price-to-book ratios for utilities that received approval to implement decoupling measures were adjusted for the P/B Index.

Chart 1: Individual Gas Utilities P/B Ratio Relative to a Peer Group Average P/B Ratio Before and After Announcement of Decoupling Approval[36]



[36] The natural gas utility peer group is comprised of the 14 gas distribution companies covered by Value Line. Price to Book data was obtained from the SNL database.

Chart 2: Individual Electric Utilities' P/B Ratios Relative to a Peer Group Average P/B Ratio Before and After Announcement of Decoupling Approval[37]



As the charts above illustrate, there is no sustained significant positive response by the investing market to the news of approval of a decoupling mechanism. A review of equity research confirms this finding. Although AG Edwards notes the positive aspects of revenue stabilization features in recent rate proceedings, it continues to consider the gas distribution utility to be exposed to significant operating risks even after the approval of a decoupling mechanism:

> *We have been impressed with the willingness of regulators to consider and authorize gas utilities weather normalization riders, performance-based rate freezes, bad-debt trackers and most recently conservation or "decoupling" mechanisms without forcing gas utilities to undergo base rate cases that are expensive and put gas utilities in a bad public light. Allowed returns on equity are typically still above 10% despite risk-free interest rates near 5%, and gas utilities have typically been able to earn near or above their authorized return. Notwithstanding the spread of these positive mechanisms, we would expect a continuation of rate increase filings in future years, as the aforementioned rate mechanisms offer only modest protection against a generally rising operating cost environment.*

Anecdotal evidence also supports the position that investors' required returns are unaffected by the implementation of decoupling measures. Very few rate orders implementing decoupling have

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[37] The electric utility peer group is comprised of the 60 electric utility companies covered by Value Line. Price to Book data was obtained from the SNL database.

provided for an explicit risk adjustment (i.e. reduction in ROE). I am not aware of any regulatory orders that approved decoupling measures for electric or gas utilities, other than the Maryland PSC orders approving decoupling mechanisms for Delmarva and PEPCO, that have explicitly imposed any reduction in allowed ROE to adjust for a perceived change in risk. Although, clearly there is some measure of risk reduction associated with the implementation of revenue decoupling mechanisms, as I have demonstrated above, investors are placing little if any incremental value on the opportunity to secure revenues. As I stated previously, it is investors' required returns that regulators estimate when setting utility rates and there is no evidence that investors are settling for lower returns in exchange for certainty of revenues. In the PEPCO and Delmarva proceedings the Companies' witness, Dr. Morin, offered a 25 basis point reduction to his recommended ROE for the implementation of a "bill stabilization adjustment." However, Dr. Morin had first correspondingly increased Delmarva/PEPCO's authorized return recommendation by the same 25 basis points, for their higher risk relative to the proxy group, due to the lack of such revenue stabilization features, since the majority of the proxy group was deemed to have such features in place.

The stock market sets prices based on investors' expectations of future events. These events may include quarterly earnings, dividend policies, M&A activity and changes in interest rates or inflation. Our analysis and understanding of the markets suggests that investors have developed the expectation that decoupling is the logical way forward to offset recently created incremental risks, and of providing benefits to customers and utilities alike, and that regulators will approve decoupling mechanisms when utilities apply for them. Decoupling mechanisms now have widespread acceptance in all regions of the country as a ratemaking approach[38] to remove disincentives to energy efficiency programs and to address declining energy demand.

The significant and growing number of utilities that have implemented decoupling measures and the fact that decoupling mechanisms largely or entirely offset recently created incremental risks, helps explain why the market response to the approval of decoupling measures has been neutral. Our analysis appears to indicate that the market views decoupling to be the new "status quo," as a result

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[38] The growing and widespread acceptance of decoupling measures is demonstrated in the Comments Prepared by James D. Simpson, Concentric Energy Advisors, in this proceeding.

of the growing number of regulatory approvals. Further, based on market expectations disapprovals of decoupling proposals are viewed negatively. Therefore, it would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

VI. SUMMARY AND CONCLUSION

These comments have made several key points and recommendations that should be reflected in the implementation of decoupling in Massachusetts: (1) Decoupling is simply a mechanism to collect a revenue target. Decoupling mechanisms should determine revenue targets in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would be triggered by expanded energy efficiency efforts. (2) Different decoupling approaches are appropriate for the short run – to allow for expedited implementation of decoupling that coincides with Massachusetts plans for expedited implementation of aggressive energy efficiency programs - and for the long run. Further, adequate flexibility should be built in the Department's decoupling directives to allow individual utilities to address their unique circumstances. (3) Essential to the success of decoupling and other critical energy and regulatory policy objectives, decoupling measures should account for yearly changes in expense–related and rate base-related costs. (4) Finally, decoupling mechanisms are being implemented by utilities across the country. Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 125 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join CEA as Chairman and Chief Executive Officer.

Representative Project Experience

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 20 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

Professional History

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

Education and Certification

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

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Boards of Directors (Past and Present)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

Affiliations

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

D.P.U. 07-50

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

Comments Prepared by James D. Simpson on behalf of Comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company

EXECUTIVE SUMMARY

James D. Simpson, Vice President of Concentric Energy Advisors ("CEA") has prepared comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company ("The Companies") to address selected issues raised in the DPU June 22 Order.

Mr. Simpson's comments provide: (1) a description of the conditions that have caused utilities throughout the country to implement decoupling measures; (2) an analysis of recent gas and electric utility experience with declining use and revenues per customer; (3) a description of decoupling approaches that have been implemented throughout the country; and (4) a discussion of decoupling measure "best practices."

In summary of Mr. Simpson's comments, the energy industry has recently been engaged in considerable analysis and discussion of the causes of declining energy demand. Decoupling in Massachusetts is supported by the same reasons that utilities throughout the country have adopted decoupling measures: (1) to align the utility's interests with public policy goals; (2) to align the customer's interest in conserving with the utility's interest in recovering its costs, (3) to reduce volatility and unpredictability of customer bills, (4) to reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability, and (5) to eliminate need for utilities to file frequent rate cases to compensate for declining use.

Mr. Simpson's comments also identify decoupling features that are common to many decoupling mechanisms and/or are innovative approaches to meeting goals and objectives of decoupling.

CEA's research on decoupling measures that have been implemented by other utilities is the basis for several important findings: (1) In all proceedings in which decoupling measures have been approved, existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure; (2) decoupling revenue targets should be determined in a manner that accounts for updates to expenses and rate base from test year levels; (3) decoupling measures typically adjust rates on an annual basis rather than more frequently; (4) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (5) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (6) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

D.P.U. 07-50

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

Comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company

Prepared by James D. Simpson

I. INTRODUCTION

By Order dated June 22, 2007, the Department of Public Utilities ("DPU") opened an inquiry[1] to investigate rate structures and revenue recovery mechanisms that may reduce barriers and disincentives to the efficient deployment of demand resources in Massachusetts. The June 22 Order included a straw proposal for a base revenue adjustment mechanism that is intended to sever the link between electric and gas companies' revenues and sales and, instead, ties company revenues to the number of customers served. The June 22 Order also included a request for comments on the elements of the straw proposal, and a further request to address thirteen specific questions.

These comments have been prepared by James D. Simpson, Vice President, of Concentric Energy Advisors[2] ("CEA") on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company ("The Companies") to address selected issues raised in the DPU June 22 Order. Specifically, these comments will provide:

- A description of the conditions that have caused utilities throughout the country to examine decoupling approaches and to implement decoupling measures;
- An analysis of recent gas and electric utility experience with declining use and revenues per customer;

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1 Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources., Docket No. D.P.U. 07-50

2 Mr. Simpson's Resume is included as Attachment A to these Comments.

- A description of decoupling approaches that have been implemented throughout the country, including an analysis of key differences between electric and gas utility decoupling approaches; and
- A discussion of lessons to be learned from decoupling measures that have been developed by utilities throughout the country.

To summarize my comments, intensified interest in energy efficiency programs is not unique to Massachusetts; this is a nationwide phenomena. Utilities and regulators throughout the country have implemented decoupling measures for reasons that are very similar to those that the Department has stated in the June 22 Order: (1) to align the utility's interests with public policy goals; (2) to align the customer's interest in conserving with the utility's interest in recovering its costs, (3) to reduce volatility and unpredictability of customer bills, (4) to reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability, and (5) to eliminate need for utilities to file frequent rate cases to compensate for declining use. I have identified decoupling features that are common to many decoupling mechanisms and/or are innovative approaches to meeting goals and objectives of decoupling.

I have also made several findings and conclusions that are relevant and instructive to the examination of decoupling in this proceeding: (1) In all proceedings in which decoupling measures have been approved, existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure; (2) decoupling revenue targets should be determined in a manner that accounts for updates to expenses and rate base from test year levels; (3) decoupling measures typically adjust rates on an annual basis rather than more frequently; (4) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (5) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (6) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

II. STATEMENT OF THE ISSUE

As stated in the June 22 Order, the Department has opened this investigation to identify ratemaking practices that will improve the alignment between (1) important state, regional, and national energy policy objectives and (2) incentives that influence the behavior of Massachusetts electric and natural gas utilities. The June 22, 2007 Order identifies these state, regional, and national energy policy objectives:

- Promote the most efficient use of society's resources.
- Lower customer bills through increased end-use efficiency.
- Enhance the price-responsiveness of wholesale electricity markets.
- Mitigate the social and economic risks associated with climate change.
- Minimize the environmental impacts of energy production, transportation, and use.

Under current ratemaking practices in Massachusetts, utilities are financially harmed by reduced sales, because sales are directly linked to revenues and earnings. Since the efficient deployment of demand resources, such as energy efficiency measures, demand response programs, and distributed resources results in reduced sales for electric and gas utilities, the current incentive system that is embedded in Massachusetts ratemaking practices is in conflict with the Massachusetts energy policy objective of promoting efficient energy use.

III. CONDITIONS LEADING TO IMPLEMENTATION OF DECOUPLING MEASURES

A. INTRODUCTION

In response to heightened focus on energy efficiency programs and the impact that energy conservation and other causes of declining energy use has on utility earnings the energy industry has engaged in considerable analysis and discussion of the causes of declining energy demand, the implications for traditional ratemaking, and non-traditional ratemaking solutions. In the remainder of this section, I will summarize recent national and Massachusetts trends in energy demand, to establish that (1) nationally, gas and electric utilities have similar growth rate patterns as those experienced by Massachusetts utilities, and (2) there is a considerable broad-based body of analysis and experience concerning decoupling approaches that can add important and useful considerations of "best practices" to the discussion of decoupling approaches for Massachusetts.

B. TRENDS IN DEMAND FOR ENERGY IN MASSACHUSETTS

Electric and gas demand, measured at the utility level, is impacted by a number of factors including the number of customers, the energy-using equipment used by those customers,[3] the intensity of use of that equipment and the energy efficiency of each type of energy using equipment. In recent years, New England gas utilities have generally been experiencing declining use per customer, which has been caused by a combination of (1) improvements in the average energy efficiency of gas equipment, (2) decreases in the intensity of use of the gas equipment, and (3) decreases in saturation rates of gas equipment.[4]

In contrast, New England electric utilities have generally been experiencing increased use per customer. Although electric equipment is subject to the same efficiency improvement trends as gas equipment, the increases in electric demand per customer can be attributed to increasing saturation rates for electric equipment.[5] A graph showing the overall increase in actual use per residential customer experienced by Massachusetts electric utilities in recent years is provided in Attachment B

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[3] That is, the number of each type of energy-using equipment.
[4] Reliable customer survey data that could provide useful insight on this subject is generally not available for specific utilities.
[5] For example, in recent years, electric demand has been impacted by increasing saturation rates for widescreen HD televisions, desk top and lap top computers, and a number of rechargeable hand-held devices.

to these comments.[6] A table showing average growth rates in electric use per customer from 2000 to 2006 is provided in Table A. Attachment B and Table A demonstrate that generally, Massachusetts electric utilities have experienced steady growth from 2000 to 2006[7] with the notable significant decline in 2006 that was triggered by customer responses to price spikes that occurred in 2005 – 2006.

Table A: Massachusetts Electric Utility Use per Customer Growth Rates

	1999 to 2000	2000 to 2001	2001 to 2002	2002 to 2003	2003 to 2004	2004 to 2005	2005 to 2006	2000 to 2006
Massachusetts Electric	-0.6%	4.1%	2.1%	5.2%	-0.8%	4.0%	-5.4%	9.1%
Boston Edison	0.2%	3.1%	1.7%	4.5%	-0.5%	4.3%	-5.5%	7.4%
Commonwealth Electric	1.0%	1.6%	2.2%	6.8%	-0.2%	2.8%	-5.2%	7.8%
Cambridge Electric	3.6%	0.8%	1.6%	4.6%	-3.6%	3.0%	-5.7%	0.3%
Western Massachusetts Electric	2.3%	3.8%	-0.5%	4.0%	-0.7%	4.4%	-5.8%	4.9%
Fitchburg Gas and Electric	1.4%	2.5%	2.9%	3.6%	-0.8%	4.3%	-4.8%	7.7%
Total Electric	0.4%	3.6%	1.8%	5.1%	-0.6%	4.0%	-5.4%	8.2%

Because of the consistent decline in use per customer experienced by gas utilities throughout the country, there has been considerable research and discussion on declining gas use, the implications of declining gas use on utilities, and ratemaking solutions to address the impacts of declining gas use. A graph showing the overall decrease in actual use per residential customer experienced by Massachusetts gas utilities in recent years is provided in Attachment C to these comments.[8] A table showing average growth rates in gas use per customer from 2000 to 2006 is provided in Table B (below). Attachment C and Table B demonstrate that Massachusetts gas utilities have experienced steady declines in actual use per customer throughout the 2000 to 2006 period.

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6 Attachment B is based on the data provided by Massachusetts electric utilities in response to the Department's Data Request DPU 01-01 in this proceeding.

7 Due to specific characteristics in the Cambridge Electric service territory, Cambridge Electric has experienced a much lower rate of overall growth in residential use per customer than other Massachusetts electric utilities.

8 Attachment C is based on the data provided by Massachusetts gas utilities in response to the Department's Data Request DPU 01-01 in this proceeding.

Table B: Massachusetts Gas Utility Use per Customer Growth Rates

	1999 to 2000	2000 to 2001	2001 to 2002	2002 to 2003	2003 to 2004	2004 to 2005	2005 to 2006	2000 to 2006
Keyspan	9.0%	-3.7%	-1.6%	15.1%	-6.5%	-1.0%	-10.7%	-9.8%
Bay State	5.9%	-3.0%	-2.0%	13.3%	-5.5%	-3.8%	-11.8%	-13.7%
FGE Gas	8.1%	-5.2%	-1.0%	10.8%	-6.6%	-3.4%	-12.1%	-17.5%
NSTAR Gas	9.4%	-7.4%	0.0%	13.8%	-6.6%	-4.5%	-12.3%	-17.6%
Berkshire	6.2%	-3.9%	-3.2%	10.4%	-6.3%	-3.0%	-11.1%	-17.1%
Blackstone	5.8%	-6.2%	1.5%	10.8%	0.0%	-4.4%	-9.7%	-9.0%
Total Gas	8.1%	-4.3%	-1.4%	14.1%	-6.2%	-2.6%	-11.4%	-12.9%

C. National Research on Customer Conservation and Declining Use per Customer

The American Gas Association issued its first report on customer conservation in 2001 and updated it in a 2003 report, Patterns in Residential Natural Gas Consumption, 1997 – 2001 (June 16, 2003) ("2003 AGA Report"). The 2003 AGA report provides a comprehensive analysis of the impact of improvements in gas equipment efficiencies on declining gas use per customer. The AGA Report provides separate analyses for the Northeast region, and is therefore more applicable to Massachusetts than an analysis of national results.

The AGA Report, which was based on government and AGA surveys,[9] found that average weather normalized Residential Heating NUPC in the Northeast declined approximately 3% between 1997 and 2001. Major factors identified as contributing to this decline included steady improvements over a long period in:

- Residential natural gas space heating equipment efficiency (measured as annual fuel utilization efficiency – AFUE):
- Residential natural gas water heater efficiency; and
- Home thermal efficiency (e.g. insulation, air infiltration).

[9] The 2003 AGA report expands on an analysis that was provided in an earlier AGA report, Patterns in Natural Gas Consumption Since 1980, American Gas Association, February 2000.

In March 2007,[10] the AGA published another analysis of the impact of customer conservation-driven declining demand, An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007 ("AGA Elasticity Report").

The Executive Summary to the AGA Elasticity Report (page 1) states that,

> "The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. …The key findings of the (Elasticity Report) are as follows:
>
> - A trend in declining use per residential natural gas customer of 1 percent annually has been documented back to 1980. This decline (sic) rate has accelerated since the year 2000.
>   - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
>   - The annual rate of decline in this 2000 to 2006 timeframe more than doubled, relative to the pre-2000 period, increasing to 2.2 percent annually.
>   - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline."

The AGA Report confirms that customer conservation has had a dramatic impact on gas LDCs nationwide.

1. Research on Causes of Declining Use

The decline in use per customer that utilities have been experiencing is the result of market forces and customers' responses to those forces. Specifically, recent declining use per customer has been the result of a combination of "passive" and "active" conservation measures and practices that customers have adopted.

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[10] The fact that the AGA has issued three reports in seven years highlights the importance of the issue of declining use per customer to AGA member utilities.

Passive conservation refers to situations in which customers are forced to replace outdated, failing gas or electric appliances with new appliances that are more energy-efficient. For example, the average useful life of residential gas space heating equipment is approximately 20 to 25 years and electric and gas water heaters last approximately 10 years. Thus, every year approximately 4% to 5% of residential customers will be forced to replace their current (i.e. 20 to 25 year old, relatively inefficient) space heating equipment, with equipment that meets current efficiency standards and is therefore significantly more efficient. Similarly, approximately 10% of residential customers will be forced to replace their current water heaters with equipment that meets the current efficiency standards. These customer actions are considered "passive" adoptions of conservation measures because these customers do not purchase more energy efficient equipment because of utility-funded conservation programs, because they are necessarily conservation-conscious, or because they have prepared an analysis of the costs and benefits of prematurely replacing old equipment with new energy efficient equipment. Rather, these customers will improve the energy efficiency of their gas or electric equipment, with an associated decrease in use per customer, simply because they have been forced to replace their current lower efficiency equipment with new equipment that is significantly more efficient.

Major residential appliances have become more energy efficient over time as a result of:

- Federally-mandated improvements in appliance efficiency.
- Advances in technology that result in better, cheaper, and more efficient appliances.
- Competitive markets and general consumer awareness of high energy costs that has motivated manufacturers to improve the energy efficiency of gas appliances.

There are a variety of voluntary, i.e. active, actions that customers can take to reduce energy consumption. These actions can be categorized as (1) short-term reversible actions or (2) long-term permanent actions. Anecdotal evidence suggests that many customers have tried to conserve energy by applying simple low cost / no cost conservation methods, such as turning down heating equipment thermostats and turning up air conditioning thermostats, closing off unused rooms, and lowering water heater temperature settings in response to recent high gas and electricity prices. These measures are viewed as reversible because they generally cause inconvenience and lifestyle disruptions that customers may not elect to continue permanently.

Examples of common long term permanent energy efficiency actions include: (a) installing high efficiency light bulbs; (b) installing additional insulation in attics, basements and outside walls; (c) installing door and window weather stripping; (d) installing setback thermostats; and (e) replacing existing windows and doors with new energy conserving windows and doors. In contrast to the short run conservation measures that are low cost or no cost, many of the permanent conservation actions involve considerable expense and require specialized expertise to install.

Before residential customers decide to install permanent conservation measures, they must have sufficient understanding of the costs and benefits of installing such measures and must have the resources to pay for their installation. Customers are generally motivated to invest in permanent conservation measures if they believe that the energy savings will offset the costs. The high costs of many of these permanent measures discourage some customers from taking actions that would produce net benefits. Typically, utility-supported energy efficiency programs, such as those that may be implemented in support of Massachusetts' energy efficiency objectives, can be economically justified because the programs remove barriers[11] to the appropriate deployment of energy efficiency measures.

[11] Barriers that can be addressed through utility or governmental programs include financial constraints and customer awareness and education.

IV. GAS AND ELECTRIC DECOUPLING MEASURES

A. GAS UTILITY DECOUPLING MEASURES

CEA has performed extensive research on gas utility decoupling measures, which provides useful insights into decoupling features that have been more widely implemented by many utilities in recent years; our review of decoupling measures that have been implemented or proposed by twenty gas utilities is summarized in Attachment D to these comments.[12] Based on the data in Attachment D, I have identified the most common gas decoupling features, which I have summarized in Table C. Although features that have been implemented by many utilities are not necessarily superior to less common approaches, CEA's analysis and regulatory experience leads me to conclude that most of the less common approaches have been implemented to address specific utility circumstances or for regulatory strategy considerations.

[12] CEA has also preformed ongoing research on gas utilities that have proposed to address declining use per customer by charging fixed customer charges that recover all distribution costs allocated to that rate class. As of the most recent update to that research, regulators had approved proposals made by three gas utilities and an additional seven proposals were pending commission decision.

Table C: Common Features of Gas Utility Decoupling Measures

Decoupling Mechanism Feature and Description	"Standard" Approach	Alternative Approaches
Target Revenues, Actual Revenues, Revenue True up: Revenue True up is the difference between Target Revenues (determined in regulatory process) and Current Actual Revenues. True up revenues are returned to or recovered from customers in a future period.	• <u>Target revenues:</u> Determined on a "per customer" basis. – Target revenues per customer are determined in rate case. – True up calculations include adjustments to reflect evaluation year changes. (For example, "growth in customers" is the most common approach.) • <u>Current Actual Revenues:</u> Based on actual per customer revenues, without adjustments. • Revenues related to cost tracker mechanisms are excluded from Target and Current Actual Revenues.	• <u>Target revenues:</u> Unique one–of-a-kind adjustments to rate case revenues. • <u>Current revenues</u>: Weather normalized (common if utility has separate WNA[13])
Evaluation period: The frequency with which the difference between Actual and Target revenues results in a change in rates to customers.	Annual	• Semi annual • Monthly
Classes affected: The rate classes that the decoupling measure is applied to.	Residential, commercial, general service	All classes
Effective dates of decoupling adjustments: The effective dates of rate changes associated with True up calculations for the most recent evaluation period.	Little consistency; often related to dates that CGAs change. Examples: • Annually, with [January, April, November] bills • Semiannually, with April and November bills • Monthly	

B. Electric Utility Decoupling Measures

CEA has also performed extensive research on electric utility decoupling measures; our review of decoupling measures that have been implemented by nine electric utilities is summarized in Attachment E to these comments. Based on the data in Attachment E, I have identified the most common gas decoupling features, which I have summarized in Table D.

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13 WNA: Weather Normalization Adjustment clause.

Table D: Summary of Common Electric Utility Decoupling Measure Features

Decoupling Mechanism Feature and Description	**"Standard" Approach**	**Alternative Approaches**
Target Revenues, Actual Revenues, Revenue True up: Revenue True up is the difference between Target Revenues (determined in regulatory process) and Current Actual Revenues. True up revenues are returned to or recovered from customers in a future period.	• Target revenues: Determined on a "total company basis." – Target revenue requirements are determined in rate case. Annual revenue requirements are determined for each year of rate plan in a manner that reflects the impact of price increases on goods and services used by the utility and projected changes in rate base. • Current Actual Revenues: Based on actual revenues, without adjustments. • Revenues related to cost tracker mechanisms are excluded from Target and Current Actual Revenues.	• Maine and Vermont decoupling mechanisms do not include deferred or balancing account for over- or under-recovery of target revenues from projected billing determinants. The decoupling of earnings from sales is dependent on the accuracy of sales forecasts.
Evaluation period: The frequency with which the difference between Actual and Target revenues results in a change in rates to customers.	Annual	Monthly
Classes affected: The rate classes that the decoupling measure is applied to.	All classes	Residential Small Commercial (Idaho only)

C. Observations and Conclusions

Our research on decoupling measures and on the associated regulatory proceedings provides several important insights and conclusions that are directly relevant to the Department's investigation into decoupling measures that will promote energy efficiency:

- In all of the regulatory proceedings that CEA reviewed in which decoupling measures were approved, all existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure.
- Electric decoupling measures generally apply to all rate classes; gas decoupling measures typically apply to residential and general service classes, but not to larger customers.
- The methodology used in electric decoupling measures to determine target revenues generally accounts for (1) changes in the electric utility's expenses in each year beyond the rate case test year, and (2) the revenue requirement impact of incremental capital projects.
- Eight of the twenty gas utilities had weather normalization adjustment measures in effect prior to implementation or proposal of decoupling; earnings and customer rate variability

due to weather was addressed in the decoupling measures that were implemented or proposed by all but a few of the remaining gas utilities.

1. Discussion

I believe that the most significant and striking of the differences between gas and electric decoupling – the recognition of the revenue requirement impact of incremental capital projects in electric decoupling - can be explained by differences in the recent experience of electric and gas utilities. As I described in Section III, Conditions Leading to Implementation of Decoupling Measures, earnings of gas utilities throughout the country have been dramatically impacted by a combination of conservation-related declining use and warmer than normal weather for several years. In contrast, the impact of declining use to electric utilities has been limited because (1) weather variability does not generally have the same impact on electric utility revenues and earnings[14] and (2) the electric response to the 2005 and 2006 price spikes was somewhat mitigated by countervailing trends that served to increase electric demand. Therefore, although gas and electric utilities have similarly compelling reasons for seeking ratemaking treatment that accounts for the revenue requirement impact of incremental capital projects,[15] gas utilities have shaped their decoupling proposals to address the more immediate and significant impacts of declining use.

The recent experience of electric utilities has been fundamentally different from gas utilities, which serves to suggest why gas and electric decoupling measures have been structured differently. In the recent past, incremental revenues from increased customer demand have been an important source of financing for electric utilities' infrastructure replacement projects. There is a general expectation in the industry that the general trend of increasing electric use per customer will return after the impacts of conservation-driven decreases in 2006 subside. Typical gas decoupling measures would eliminate this source of infrastructure project financing, because these measures have not accounted for infrastructure replacement programs or allowed for trends of increasing use per customer[16] in the determination of Target Revenues. It is because of these considerations, I believe, that most of the electric utility decoupling measures include a consideration of infrastructure improvement projects.

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14 In addition, electric utility earnings are affected by weather variability in the summer (air conditioning loads) and winter (heating loads)

15 Gas utilities throughout the country must address substantial infrastructure projects - primarily to replace cast iron and bare steel mains and services. Electric utilities also have significant ongoing infrastructure replacement commitments.

16 Trends of increasing use per customer would have to be determined prior to reflecting the impact of incremental energy efficiency programs.

I believe that the Department could benefit from CEA's research to identify decoupling approaches that would not introduce financing-related barriers to gas and electric utilities' infrastructure replacement programs.

V. SUMMARY

By virtue of the number of decoupling measures that have been implemented by gas and electric utilities, there is a growing consensus that traditional ratemaking does not provide utilities with a reasonable opportunity to earn a fair rate of return, especially in periods that energy efficiency programs are adding to significant customer-driven conservation.

CEA's research provides useful guidelines for developing a well-designed decoupling measure: (1) Revenue Targets should be determined to account for expenses and rate base that have been updated from test year levels; (2) decoupling measures typically adjust rates on an annual basis rather than more frequently; (3) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (4) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (5) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 28 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

Representative Project Experience

REGULATORY AFFAIRS

Representative engagements and responsibilities include:

- Prepared strategic assessment of PBR options for South Central utility
- Prepared review of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared review of sales forecast process and results of Midwestern utility
- Prepared review of sales forecast for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared Marginal Cost Study and rate design for Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

BUSINESS STRATEGY AND OPERATIONS

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition for entrepreneur service provider to coal generating plants.
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

CONTRACT NEGOTIATIONS

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America fly ash separation site in four years
- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions

- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

Professional History

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

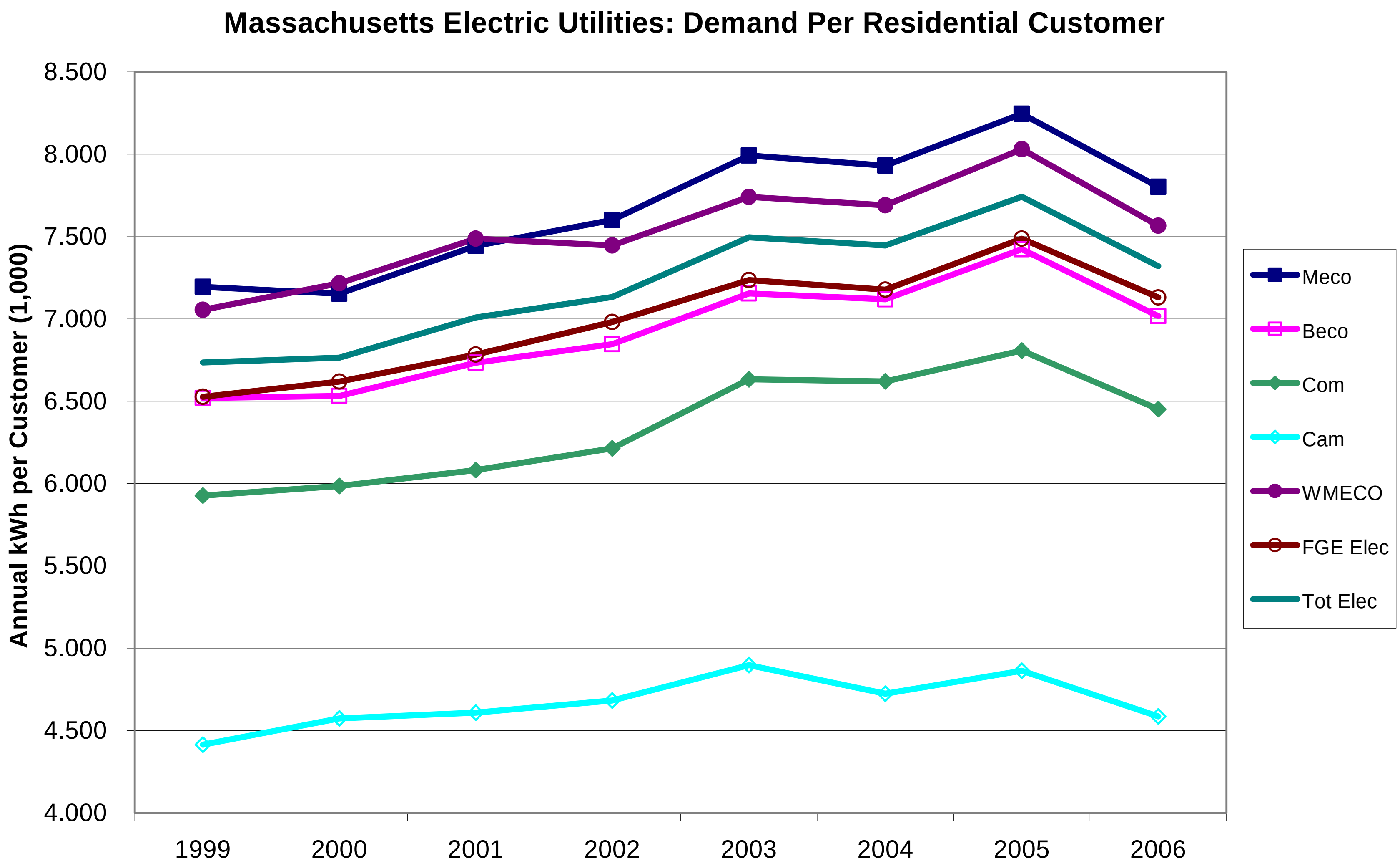
Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

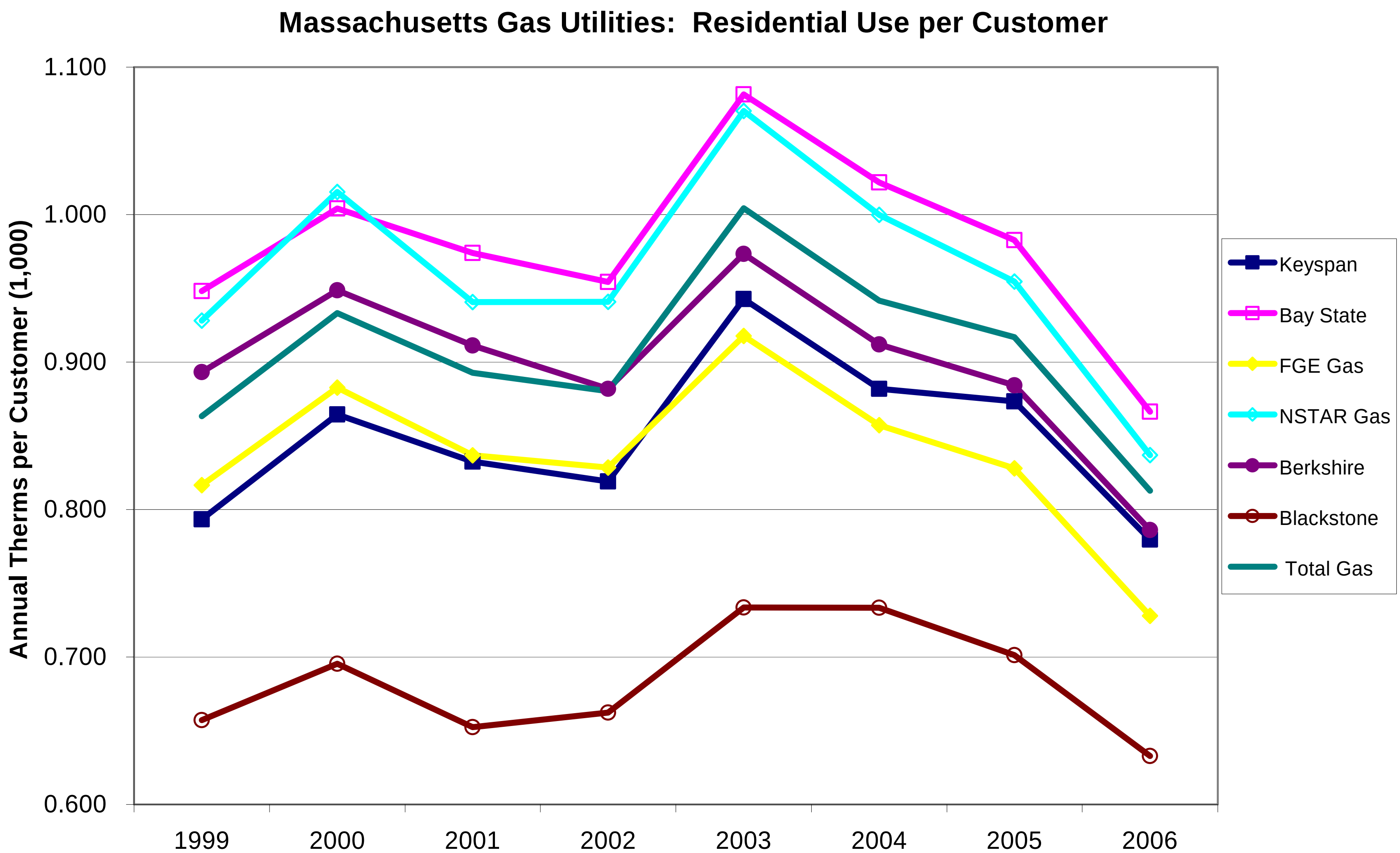
Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

Education

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude



The data in this graph are actual annual kWh per customer values, not adjusted for weather.



The data in this graph are actual annual Therms per customer values, not adjusted for weather.

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
1	AR	Arkansas Oklahoma Gas Corp.	D-07-026-U	Pending	Monthly actual class revenues compared to target (rate case) revenues[17]	Residential and Small Business	Annual true up	WNA[18] CGA[19] Municipal Tax Clause
2	IL	Peoples Gas Light and Coke Co. and North Shore Gas Co.	D-07-0241, 0242	N/A Pending	Monthly difference between actual and TY[20] ("Test Year") margin per customer, times TY customers, divided by estim. volumes, 2 months later. Actual and target revenues is deferred	Service classes 1N, 1H, and 2	Monthly	CGA Municipal taxes Environmental costs
3	NY	National Fuel	C-07-G-0141	N/A Pending	Difference between annual TY UPC and current year WN UPC, times tail block rate times customers	SC 1,SC 2 (Res) and SC 3. (GS)	Annually; 12 months ended December data. Effective March 1	WNA
4	AR	CenterPoint Arkansas	06- 16 1 -U	N/A Pending	Annual actual revenues compared to rate case revenues[18] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels WNA currently in effect[1]	Residential Firm Sales Service, RS-1, Small Commercial Firm Sales Service, SC-1, Small Commercial Firm Sales Service - Off Peak, SCS-2	Annual true up, January – December adjustment rate in effect following July through June	WNA
5	DC	Washington Gas Light Co.	D-1054-G-2	12/21/2006 Pending Latest Filing (8/1)	Billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth	All classes	Monthly with 2 month lag between calculation and billing of adjustment	

[17] This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
[18] WNA: Weather Normalization adjustment clause.; WN: weather normalized
[19] CGA: Cost of Gas Adjustment clause.
[20] TY: Test year

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
6	TN	Chattanooga Gas		Separate hearing in Dec 2007	Proposed decoupling is currently being addressed as part of Phase II of proceeding.	N/A	N/A	WNA
7	AR	Arkansas Western Gas	D-06-124-U N/A	7/13/2007	Annual actual revenues compared to rate case revenues[21] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels Separate WNA	Residential (RS-l), Business 1- Sales and Transport (B-l), and Business 2- Sales and Transport (B-2) rate classes.	Annual true up, August – July; adjustment rate in effect following January through December	WNA Tax and fee
8	CA	PG&E	AP-9712020De-0002046	5/27/2004	Rate Plan Revenue Requirement	All	Annual	23 Balancing accounts, Adjustments • Core, non-core fixed cost; pension contribution 7 memo accounts • Catastrophic Event, Advanced Metering Infrastructure, Financial Hedging
9	CA	SOCal Gas			PBR[22] price cap rate plan	All	Annual	18 Balancing Accounts • Pension, PBOP[23], Core, non-core fixed cost 26 memo accounts • Catastrophic Event, Intervenor Award ESM[24]

21 This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
22 PBR: Performance Based Ratemaking
23 PBOP: Post-retirement other than Pension expense
24 ESM: Earnings Sharing Mechanism

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
10	CA	Southwest Gas	3/16/2004		Rate plan revenue requirement Attrition year increases could be adjusted down if pipe replacement targets missed Actual margin revenues compared to authorized levels	All	Annual	Catastrophic Event, Public Purpose Program, Low Income Energy Efficiency
11	CO	Public Service Co. of CO	D-06S-656G	6/18/2007	NUPC true up mechanism Difference between WN actual use per customer and TY UPC, times margin rate times actual customers	Residential RG	Annual	
12	IN	Southern Indiana Gas and Electric	C- 43046 C-43112	12/1/2006 8/1/2007	85% of difference between actual class margins and TY margins by class, adj for growth in customers	Residential, General Service sales; School transportation	Annual recovery of accumulated deferred balance; with reconciliation	Bad debt gas , pipeline safety, bare steel replacement (PSA), normal temperature adjustment
13	MD	Washington Gas Light Company	Case No. 8990	8/6/2005	Calculate billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth Reconciliation of actual and target revenues	Rate Schedule Nos. 1, 1A, 2, 2A, 3 and 3A	Monthly with 2 month lag	
14	NC	Piedmont Natural Gas	D-G-9,SUB499	11/3/2005	Rev Adj by class by month = Target revenues – Actual revenues.: Target: actual customers x (TY base load/cust + TY TS factor x Normal HDD) Interest on deferred	Rate schedules 101, 121, 102, 132, 152, 162	Adj Factor changes Apr, Nov, based on deferred bal at Jan, Aug	Pipeline integrity, PBOP regulatory assets Bad debt (gas)

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
15	NJ	South Jersey Gas /New Jersey Natural Gas	11/9/2006		Monthly difference between current actual and TY NUPC, times predetermined weighted margin per therm times actual monthly customers Capped to limit ROE to 10.5%	Resid, Resid Transport, Gen Svc High LF, Comprehensive Transportation and Balancing, Gen Svc Low LF, Small Commercial Rebundled Trans, ED	Annual	WNA
16	OH	Vectren	05-1444-GA-UNC	9/13/2006	Difference in actual WN revenues, rate case revenues, adjusted for growth in customers. Actual and target revenues are reconciled	Residential sales/ trans: general sales / trans	New rate effective November 1 annually,	
17	OR	Northwest	Renew: UG 163	8/22/2003 Initial: 9/12/02; renew 8/25/05	Partial decoupling: Base line rate case per cust, adj for price elasticity compared to actual weather norm UPC	Res 1, 2 Commercial 1, 3, 31	Annual, eff Oct 1 each year; adj based on deferred balance as of June 30.	Separate WNA
18	UT	Questar Gas	Docket No. 05-057-T01	5/26/2006	Difference between rate case margin per customer, and actual revenue, times actual monthly customers, Reconciling	GS-1, GSS	Semiannually, adjustment to base rates made to amortize current balance over 12 months	WNA: separate
19	WA	Avista	UG 060518	12/21/2005	Actual WN sales, with new customers removed, compared to TY monthly sales. revenues calculated by multiplying sales diff by approved rate; 90% of diff is deferred Deferral subject to ESM and DSM performance Impact capped at 2%; difference remains in deferred.	RS 101 (residential and small commercial)	Annual, July – June; new adjustment effective Sept 1 Nov 07 – Oct 2010	Tax Adjustment

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
20	WA	Cascade Natural Gas Corp	UG-060256	1/12/2007	Difference between rate case margin per customer and actual WN margin per customer times actual customers Actual and target revenues reconciled	RS 503, 504 (Residential, Commercial)	Annual	

					Decoupling				
	State	Company	Docket Number	Date of Decision	Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
1	California	Pacific Gas and Electric Co.	AP-9712020De-0002046	5/27/2004	Rate Plan Revenue Requirement	All	Yes	Annual	ESM, PBR 28 Balancing Accounts: • Baseline, pension contribution 34 Memo Accounts • Catastrophic event, Hedging, Gas procurement Audit, Low Income Energy Efficiency
2	California	San Diego Gas & Electric Co.	AP-0212028De-0412015	12/8/2004	Post Test Year Revenue Requirement	All	Yes	Annual	ESM; PBR 25 Balancing Accounts: • Distribution fixed cost, Pension/ PBOP, Tree trimming 34 Memo Accounts • Catastrophic event, Distributed Generation Implementation, Advanced Metering Infrastructure, Low Income Energy Efficiency
3	California	Southern California Edison Co.	AP-0205004De-0407022	4/22/2002	Post Test Year Revenue Requirement	All	Yes	Annual	ESM; PBR 14 Balancing Accounts: • Base Revenue requirement Pension/ PBOP, Tree trimming 15 Adjustment Mechanisms • PBR distribution revenue requirement, Low Income Energy Efficiency
4	Idaho	Idaho Power Co.	C-IPC-E-04-15	3/12/2007	Rate case revenue requirement per customer	Residential, Small Commercial	Yes	Annual	• Fixed Cost Adjustment; Applied to Residential, Small Commercial • Power Cost Adjustment • Energy Efficiency Rider

	State	Company	Docket Number	Date of Decision	Decoupling: Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
5	Maine	Bangor Hydro-Electric	2001-410	6/11/2002	Rate plan revenue requirement	All	No	Annual	Annual Price Change formula: • Settlement Basic Rate Reductions, Mandated Costs (force majeure non-recurring events, accounting, federal or state legislative, regulatory or tax changes), Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties
6	Maine	Central Maine Power	1999-666	11/16/2000	Rate plan revenue requirement	All	No	Annual	Price cap adjustments: • Major storms, disasters, changes in law or regulations - CMP liable for 1st $3 million in extraordinary costs in any given year. • Gains and losses on sales of property • ESM, SQ, Reliability
7	Maryland	Delmarva Power & Light Co.	C-9093	7/19/2007	Rate case revenue requirement per customer	R, R-TOU-ND, SGS-S, GS-SH, GS-WH, LGS and GS-P	Yes	Monthly – 2 month lag	Riders • Universal Service Program, Franchise Tax, Environmental Surcharge, Bill Stabilization Adjustment
8	Maryland	Potomac Electric Power Co.	C-9092	7/19/2007	Rate case revenue requirement per customer	R, R-TM, GS, GT LV, GT 3A, GT 3B, MGT LV II, MGT LV III, MGT 3A II, MGT 3A III, T, EV TM-RT.	Yes	Monthly – 2 month lag	Riders • Universal Service Program, Delivery Tax Surcharge, Environmental Surcharge, Bill Stabilization Adjustment

	State	Company	Docket Number	Date of Decision	Decoupling				
					Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
9	Vermont	Green Mountain Power Corp.	D-7175	12/22/2006	Rate changes based on updated COS	All	No	Annual	Exogenous factors: • Changes in tax laws, GAAP, FERC ISO rules • Non-weather loss of load, Major unplanned maintenance costs or investments (e.g. storm related, major repairs) ESM